Appendix A

Policy Office Electricity Modeling System (POEMS) and Documentation for Transmission Analysis

Overview of POEMS

The Policy Office Electricity Modeling System (POEMS) integrates the Energy Information Administration (EIA) National Energy Modeling System (NEMS) with the detailed electricity market model TRADELEC™, developed by OnLocation, Inc. NEMS is an integrated energy model with supply and demand modules representing the U.S. energy system. In POEMS, TRADELEC™ replaces the Electricity Market Module of NEMS to add detail and disaggregation. TRADELEC™ was designed specifically for analyzing competitive electricity markets and the transition from regulated markets. TRADELEC™ incorporates the features necessary to analyze key policy questions: stranded costs, consumer prices, mix of new construction, impact of increased electricity trading, and interaction with environmental policies.

POEMS has been used to support DOE's analysis of the Comprehensive Electricity Competition Act proposed by the Clinton Administration. For various participants in electricity markets, POEMS has been used to assess regional markets, forecasting electricity prices, supply, and demand under alternative economic and fuel price scenarios. The model has also been used to assess the impact of alternative environmental policies on utility industry capital turnover and inter-fuel substitution.

For the National Transmission Grid Study, the dispatch and trade portion of TRADELEC™ was used as a stand-alone model with generating capacity, fuel prices, and electricity demands held constant. In other words, the other fuel supply and demand modules were not used, and the capacity expansion module was turned off. The analysis focused on a single year (2002). Hence, the impacts of changes in these other variables is small and detract from the focus on transmission and trade flows. Therefore, documentation included in this appendix focuses on the dispatch and trade portions of TRADELEC™ and does not describe its other modules and features, (e.g., capacity expansion, retail pricing, and demand response.)

TRADELEC™ Electricity Model

The heart of the TRADELEC™ model is market-driven electricity trade over the existing electricity transmission system. Electricity trade is solved as a function of relative prices, transmission availability, and a hurdle rate that is designed to reflect the additional costs of handling market trading. TRADELEC™ represents transmission inter-ties at existing transfer interfaces. Current and future transmission bottlenecks may limit trade flows among certain buyers and sellers when transmission capacity is reached. This would result in final regional price differences that exceed the cost of transmission and trading.

The trading function is critical in determining competitive prices for electric power and in measuring efficiency gains from restructuring the electricity industry. By explicitly solving trade relationships, TRADELEC™ offers insights into pricing patterns and motivations for interregional trading.

In the absence of transmission constraints, electricity prices nationwide would converge to a single value with local delivery prices varying only by differences in the cost of transmission (including line losses) and distribution services. However, the tendency in competitive markets toward a single price does not mean that there will be no market separation. Because transmission is neither unconstrained nor without cost, separable regional electricity markets are likely to be observed as model solutions evolve. Additional regional constraints, such as region-specific pollution abatement measures, could further increase regional price differences even in fully competitive power markets.

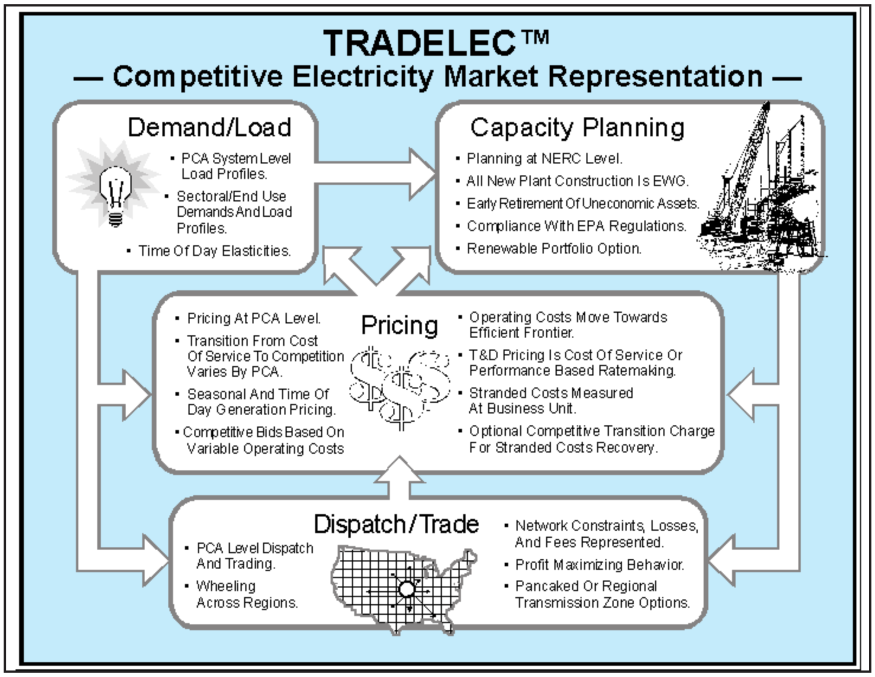

Figure 1: Components of the TRADELEC™ Model

Model Description and Structural Assumptions

Electricity Demands and Load Shapes

A unique aspect of POEMS is its representation of the load-duration curves with vertical rather than horizontal time blocks. This approach ensures that trades among regions are fulfilling the same requirements and that power generated at one time (such as during night hours) is not being used to satisfy power demands at another time (such as during peak daytime hours). The definition of the time blocks is flexible. For this transmission study, the annual load in each region is represented by total of 864 load slices: 24 hours for three typical day types (weekday, weekend day, and peak day) within each of the 12 months.

Dispatch and Trade

TRADELEC™ is a network model of electricity dispatch, trade, capacity expansion, and pricing, as shown in Figure 1. The model operates using POEMS' 69 regions or power centers, illustrated in Figure 2. These regions are combinations of the roughly 150 power control areas in the U.S. although some power pools are disaggregated to reflect transmission constraints between zones. POEMS regions are represented as a series of nodes, connected by transmission inter-ties with specific transfer capabilities. There are more than 300 transmission paths in POEMS. Supply resources within each POEMS region, consisting of utility plants, exempt wholesale generators, traditional and non-traditional cogenerators, and firm power contracts, are represented in considerable detail. Plant characteristics, such as capacity, heat rate, and forced and maintenance outage rates, are represented based on data in EIA filings and the North American Electric Reliability Council Generating Availability Data System data. TRADELEC™ incorporates financial, operational, and physical data representing virtually every significant operating electric utility in the U.S. and the transmission inter-ties among them.

Representation of Generation Plants

The plant input file to POEMS consists of virtually all existing units in the U.S. Plants currently under construction that are expected to be on-line during the year 2002 are included as well. Each unit in the plant input file is combined with like units to form dispatchable groups. The process of combining units is flexible, but, at a minimum, combined units serve the same demand region and are physically located in the same supply region, use the same fuels with the same type of prime mover, and have the same in-service period. Dispatchable capacity groups also have similar heat rates, and renewable groups have similar utilization patterns. Currently, there are more than 7,000 plant groupings in the model. There are over 100 dispatchable plant groupings per POEMS region on average, with the largest POEMS regions having 300 to 500 plant groups. A merit order dispatch algorithm is initially employed to determine generation in each time segment prior to trade.

Trade

Network interregional trade is solved to maximize the economic gains from trade by ordering trades in descending order, starting with the trade that contributes the largest efficiency gains first. Succeeding trades continue until available transmission opportunities or all possible gains are exhausted. The primary economic and physical limits to trade are imposed by means of alternative scenarios for transmission fees, losses, transmission capacity, and hurdle rates. Thus, integrated interregional trade is modeled to operate in much the same fashion as a full-fledged, time-block power auction.

Transmission Costs and Capacity

POEMS transmission path and nodal trading limits were derived from a number of sources, including the Western States Coordinating Council (WSCC) 2001 Path Rating Catalog and various power flow cases filed with the Federal Energy Regulatory Commission (FERC) and evaluated using the Power Technologies Inc. PSS/E power-flow modeling system.

Transmission costs are reflected through representation of transmission tariffs that can be implemented on a POEMS region or Regional Transmission Organization (RTO) level. RTO definitions are flexible and can be changed for each scenario. The model uses pancaked transmission fees, in which a trade is assessed a fee for each region that it passes through, or regional postage stamp fees, where one tariff is established for each RTO that is composed of several POEMS regions. (The use of these fee structures is described in the section below on transmission study scenarios.) Transmission is treated as cost of service, and any revenue collected through wholesale trade is used to offset the transmission costs borne by retail customers. The wholesale transmission fees are set to a percentage (generally in the range of 50 to 80 percent) of the average FERC Order 888 stage one, pro forma, point-to-point tariff.

Transmission losses are modeled as a nonlinear, distance sensitive measure. In addition, a user-specified "hurdle level" is input to limit transactions to those that provide a specified minimum level of economic gain. The hurdle rate can be adjusted to reflect reductions in potential inefficiencies and transactions costs as markets provide greater incentives to exploit profitable trades. The market simulation is conducted within each of the time and season load slices that are modeled, and chronological simultaneity is maintained.

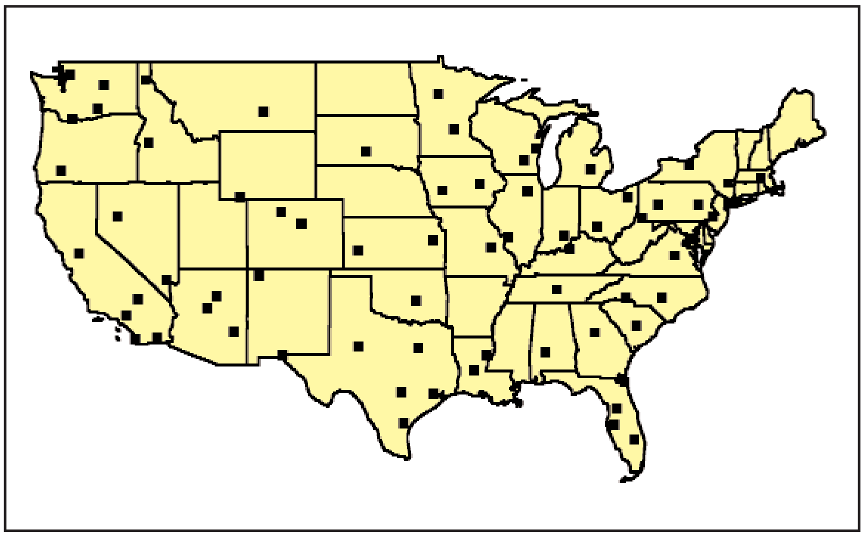

Figure 2: Current TRADELEC™ Regions.

Pricing

Wholesale generation prices are established for each POEMS region for each time and season load slice. The market-clearing price equals the marginal cost or bid price of the most expensive generating unit that is operating. This next marginal unit could be native to the POEMS region or determined through trade with other POEMS regions.

The competitive bid price for each unit is assumed to be its marginal cost in accord with the standard characterization of competitive markets. Marginal costs are the sum of fuel costs and the variable portion of operating and maintenance (O&M) costs.

Fixed and Variable O&M Costs

POEMS initially puts all O&M costs into a fixed O&M account and allows the user to determine how much of the fixed costs should be considered variable. For this transmission study, one-half of O&M cost is assumed to be included in generator bid prices. In addition, historical levels of O&M costs are expected to decrease over time because of the pressures of competition. POEMS includes a feature that allows the user to specify O&M cost targets by plant type along with a specification of a percentage progress towards that target by plant type and year. Competitive pressures are also expected to spill over into the regulated segment of the industry. POEMS allows the user to specify transmission and distribution productivity improvements. Competition is also expected to result in heat rate improvements, which affect the generation price. POEMS includes a feature that allows the user to specify target heat rates by plant type along with a specification of a percentage improvement towards that target by plant type and year.

Transmission Scenarios

All the POEMS scenarios are projections based on expected electricity demand, capacity, and fuel prices for the year 2002.

Current Markets

The Current Markets case is an approximation of the current status of transmission policy. Several regions are represented as RTOs with postage-stamp transmission fees. Under postage stamp fees, transmission assets within an RTO are pooled on a fixed-cost basis. Each member of the RTO pays a single charge for access to the transmission grid; there are no additional charges for each transaction. A fee is only paid for transactions that cross RTO borders. The remaining regions are assumed to have pancaked rates, in which a separate fee is assessed for movement across each power center. The transmission fees are established based on 50 percent of calculated FERC pro forma tariffs. In addition, the gain from all trades must exceed a hurdle rate of $3.00 per MWh, which represents the transaction costs and barriers associated with arranging transmission paths and finding trading partners.

POEMS tracks electricity generation and prices for each of the 69 regions both before and after any trade among the region occurs. The current markets case was used to estimate the benefits of wholesale electricity trade given the current physical and institutional operation of the transmission grid by comparing electricity production costs and prices before and after trade. It does not distinguish increased trade due to wholesale competition from economy trades that routinely occurred among neighboring utilities prior to FERC Orders 888 and 889.

No Congestion For Four ISOs

A No Congestion case was constructed in which the transmission paths within four major ISOs were increased so that no economic flows were prevented. The four ISOs are PJM, New York, New England, and California.

Transmission Fee

In the Transmission Fee case, there are five large RTOs, and each is assumed to have a postage-stamp rate structure. The hurdle rate is reduced to $1.50 per MWh to reflect reduced transaction costs expected from large RTOs.

This analysis is not a complete estimate of the benefits of RTOs, nor does it represent DOE’s position on appropriate geographic boundaries for RTOs. This analysis only illustrates the importance of transmission fees in shaping trade and congestion patterns. Eliminating pancaked rates is only one of the expected benefits of RTOs.

Calculation of Economic Benefits of Trade

There are several ways to measure the economic benefits of trade. Two measures have been adopted in this study. The first is the reduction in net generation costs that results from trade. Exporters will have an increase in fuel and operating costs because they are producing more power while importers will have reduced costs. Assuming competitive markets in which power plant owners bid their marginal operating costs, trading will always result in a net reduction in generation costs. Some regions rely heavily on imports and do not maintain sufficient, even expensive, capacity to meet their native loads. For these regions, we assessed a $100-per-MWh generation cost for unmet demand and used this value to calculate reductions in generation costs. For example, if a region is unable to meet its own demand and imports power for $70 per MWh, the generation cost savings is $30 ($100-$70), multiplied by the amount of the imports.

A second measure of benefit is the impact on consumer prices. The change in wholesale prices can affect consumer prices in one of two ways. If the area remains under traditional cost-of-service regulation, wholesale costs and revenues are treated as utility expenses that flow through to consumer rates. We have assumed that 75 percent of the gain, either the additional margin made by exporters or the reduced net costs of the importers, is passed through to the consumer. The other 25 percent would be allowed to go to the shareholders as an incentive for utilities to maximize the benefits of trade.

For regions that have moved to full retail competition, consumer prices will, on average, follow wholesale prices. The consumer savings from trade are computed as the change in prices before and after trade, multiplied by total demand. In general, the impact will be larger than in regulated regions where only the amount of electricity that is traded is used in the computation of benefits. The regions that are considered to have competitive pricing at the retail level are the same as those that have RTOs in the Base Case: PJM, New York, New England, ERCOT, and California.

The change in production costs and consumer costs for each of the scenarios modeled in POEMS are given in Table 1.

POEMS underestimates the savings to consumers from wholesale electricity trade and the costs of congestion for three reasons. First, POEMS does not capture the effects of

Table 1

Region	Base Case Transmission Fee Type	Transmission Fee Region
PJM—Pennsylvania, New Jersey, Maryland	postage stamp	Northeast
NEPX—New England	postage stamp	Northeast
NYPP—New York	postage stamp	Northeast
ECAR—East Central Area Reliability Coordination Agreement	pancaked	Midwest
MAIN—Mid-America Interconnected Network	pancaked	Midwest
MAPP—Mid-Continent Area Power Pool	pancaked	Midwest
SPP—Southwest Power Pool	pancaked	Midwest
ERCOT—Electric Reliability Council of Texas	postage stamp	ERCOT
FRCC—Florida	pancaked	Southeast
SERC—Southeastern Electric Reliability Council (excluding Florida)	pancaked	Southeast
WSCC/AZN—Arizona/ New Mexico	pancaked	West
WSCC/CNV—California	postage stamp	West
WSCC/NWP—Northwest Power Pool	pancaked	West
WSCC/RA—Rocky Mountain Area	pancaked	West

Table 2: Annual Economic Costs (Millions)

Scenario	East		West		Total	
	Generation Cost (change from base)	Consumer Costs (change from base)	Generation Cost (change from base)	Consumer Costs (change from base)	Generation Cost (change from base)	Consumer Costs (change from base)
Current Trade*	-$3,254	-$4,248	-$8,944	-$8,351	$-12,198	-$12,599
No Congestion Within Four ISOs	NA	NA	NA	NA	-$89	-$157
Transmission Fee	-$375	-$726	-$35	-$307	-$410	-$1,033

*For the current trade case, the change in generation costs and consumer costs represents the decrease in costs that results from the base case level of wholesale electricity trade among the model's 69 subregions compared to a case in which no wholesale trading is allowed. For the remaining cases, the reported savings are the change from the current trade case.

price spikes. POEMS assumes that prices are determined by the marginal costs of the last generator needed to meet load in each subregion. In reality, however, price spikes often occur when supplies become tight and additional electricity cannot be imported. Prices might also rise in constrained regions if generators are able to exercise market power. Within competitive markets, transmission investment to reduce congestion might sometimes lead to only small changes in generation costs, but the mere presence of additional transmission capacity creates contestability in each of the local markets that will curb potential market power and reduce prices to consumers. These benefits are not captured by POEMS.

DOE calculated the increase in congestion costs resulting from prices spikes for four regions in the U.S.: California ISO, PJM, New York ISO, and ISO New England. Price spikes are assumed to occur during the hours when at least one transmission link into the region was congested and demand was greater than 90 percent of peak demand. Total congestion costs (cost to consumers) for these four regions combined are initially estimated to be $157 million annually (without price spikes). When prices spike an additional $50 per MWh during these periods, congestion costs nearly double to $300 million. When prices spike an additional $100 per MWh during these periods, congestion costs nearly triple to $447 million.

Second, POEMS captures only the benefits of trade between regions and does not address trade within regions. For example, all of New England is represented as a single region within the model, so benefits from trade within New England are not reflected in the analysis. Accordingly, the model does not represent transmission constraints within regions and does not account for these congestion costs in the analysis. California's Path 15, which is often congested, is not specifically represented in POEMS.

Finally, POEMS is not designed to analyze reliability benefits. Increased transmission capacity will generally improve the overall reliability of the grid and allows regions to share capacity reserves. Although the risk of blackouts is generally small, blackouts usually entail very high economic costs. As such, even a small reductions in the risk of a blackout will have substantial benefits.